GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

PLANNING REPORT NUMBER ONE

DIRECT ECONOMIC IMPACT OF TOTAL DRILLING ACTIVITY 1981 - 1990

PETROLEUM DIRECTORATE
SEPTEMBER 1982

ISSUED UNDER THE AUTHORITY
OF

THE HONOURABLE WILLIAM W. MARSHALL, Q.C.
MINISTER

AND

S. M. MILLAN
EXECUTIVE DIRECTOR

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

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Foreword

In May 1981, the first in a series of reports dealing with the direct economic impact of offshore petroleum activity was released. That report, entitled "Economic Impact of Future Offshore Petroleum Exploration", dealt with seismic acquisition and processing as well as exploratory drilling.

Similar to previous impact reports, emphasis here is placed on planning and the use of a consistent methodology. By outlining the interaction of exploration, delineation, development and production activities, a framework for planning and decision-making in government and the community as a whole can be obtained.

This report provides an update of the exploration drilling forecasts contained in the May 1981 report. A highly generalized geological play analysis is then applied to the identified geological structures in order to generate estimates of showings and commercial discoveries. By applying a series of assumptions on the size distribution of reserves, the number of delineation wells per showing or commercial discovery, and the relationship between reserve size and the development well drilling program, a series of forecasted delineation and development drilling activities is presented. As with the previous report, the drilling activity is then analyzed in terms of the demand for goods and services and the resulting expenditures and employment.

Future reports in this series will deal with the direct impacts of the development and production phases.

It cannot be emphasized too strongly that, even if a consistent methodology is applied, the resulting forecasts are just that, forecasts, and should not be treated as the definitive word on the subject. The international petroleum industry will always be very uncertain and many things could happen, literally overnight, which would cause the forecasts to change dramatically. Nevertheless, even with all of its uncertainties, forecasting is a necessary prerequisite to sound policy and planning.

Any forecasting exercise is extremely hypothetical and involves a large degree of uncertainty that increases with time and with the stage of drilling activity modelled. However, the forecasting methodology developed here outlines a realistic interaction of exploration, delineation and development drilling activities and the range of estimates used gives our model enough flexibility and scope to capture the limits of reasonably expected economic impacts.

Steven M Millan

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Summary and Conclusions

In "Economic Impact of Future Offshore Petroleum Exploration", by the Department of Development and the Petroleum Directorate in May 1981, forecasts were made of the direct economic impact of seismic acquisition and processing and exploratory drilling activity in the offshore portion of Newfoundland and Labrador. At that time, it was intended to deal with the delineation and development phases in a single report. Due to the scope of the development phase and the commitment of the government of Newfoundland and Labrador to provide information to the public as soon as it becomes available, it was decided to present the impact of delineation and development drilling at this time and to deal with the other aspects of the development phase in subsequent reports.

The exploration drilling forecasts of previous reports were updated in order to reflect the changing conditions over the past year and the increased knowledge gained as a result of the 1981 drilling program.

After developing the exploration forecasts, a series of success ratios were applied in order to reflect the possibility of a showing that proves to be noncommercial or a discovery that proves to be commercial under conditions at the time of development. Based upon the number and location of these showings and commercial discoveries, a series of delineation and development wells is then generated.

On the basis of the forecasts of total annual drilling activity, the report provides detailed information on the quantities of goods and services by major expenditure item, the manpower requirements and the total costs in terms of expenditures on goods and services and the resulting wages and salaries. Total employment ranges from an annual low of 809 manyears under the low forecast case to an annual high of 4822 manyears under the high forecast case. Associated wages and salaries range from an annual low of 28 million dollars to an annual high of 183 million dollars. Total expenditures range from an annual low of 242 million dollars to an annual high of 2250 million dollars.

At least two important conclusions can be drawn from this analysis. Firstly, direct drilling operations alone have the potential to provide significant economic benefits to the local economy. Secondly, as the following table illustrates, a large number of drilling rigs and supply boats will be required during this decade. Local ownership of some of these vessels would greatly enhance the benefits that Newfoundland, the Atlantic region and thus Canada as a whole would obtain from the offshore.

Supply Vessel and Drilling Rig Requirements 1982-1990

Year	Rigs			Supply Vessels		
	Low	Medium	High	Low	Medium	High
1982	5	5	5	15	15	15
1983	6	8	12	18	24	36
1984	7	12	19	21	36	57
1985	8	13	21	29	39	63
1986	6	11	23	18	33	69
1987	3	13	26	9	39	78
1988	6	14	26	17	41	77
1989	5	13	27	13	37	79
1990	9	16	31	22	42	87

The construction of supply boats and drilling rigs would help meet many of the objectives of servicing a heavy industry base, earning foreign exchange and meeting domestic demand. Such activity would be beneficial in the creation of a national petroleum service company and the achievement of energy self-sufficiency in Canada.

1. Introduction

The first report dealing with the direct economic impact of petroleum exploration in the Newfoundland and Labrador offshore area was prepared by the Petroleum Directorate and the Department of Development and was entitled "Economic Impact of Future Offshore Petroleum Exploration".

This report combines updated forecasts of the exploratory drilling data base with forecasts of delineation and development drilling in order to obtain estimates of the direct economic impact of total drilling activity.

The other aspects of the development and production phases such as platform construction, template and module fabrication, and oil and gas transportation will be covered in subsequent reports.

The following chapter supplies a brief geological and engineering description of the Hibernia field. The parameters upon which the Hibernia development well forecast is based are also supplied.

The third chapter describes the drilling activities which are the basis of the economic impact forecasts of chapter four.

The fourth and final chapter provides forecasts of the impact of exploration drilling, delineation drilling, development drilling for Hibernia and development drilling for subsequent fields. The forecasts are analyzed in terms of the demand for goods and services, total expenditures and employment.

Before proceeding with the remaining chapters, it is important to stress the difficulty associated with forecasting, especially in an inherently uncertain industry such as the offshore petroleum industry. The assumptions and information upon which the forecasts are based change rapidly and could render these forecasts out of date within a very short period of time. In view of this uncertainty, the practice followed in previous reports of giving a range of forecasts is also observed here. This range not only provides the authors' best estimate of the future but also establishes what is believed to be reasonable lower and upper limits around this estimate.

2. Description of the Hibernia Field

2.1 Introduction

The Hibernia field was discovered in September 1979 with the drilling and completion of well P-15. Testing of this well showed the presence of oil in three separate horizons, Jeanne d'Arc, Hibernia and Avalon. The P-15 well had an estimated oil production capability in excess of 3180 m^3 per day. A subsequent well, Hibernia O-35, penetrated the Avalon and Hibernia sands but did not encounter the Jeanne d'Arc sands. Although both sands were thicker at the O-35 location and the Avalon sands were oil bearing, the Hibernia sands were water saturated. The production capability of the O-35 well is comparable with that of the P-15 well.

In addition to P- 5 and O-35, three other wells, B-08, G-55A and K-18 have been drilled and tested. Before its sinking on February 15th, the Ocean Ranger was drilling at a sixth location, J-34. This well has been drilled to 3865 meters with a projected total depth of 4267 meters. In the B-08 well, hydrocarbons were encountered in both the Avalon and Hibernia sands as well as in a third sand known as the seismic B-Marker. Of the three zones encountered in B-08, the Hibernia zone was most productive. The Avalon sands were the only sands encountered in the G-55A well and these proved to be water saturated. All three zones present in B-08 were also present in K-18.

Although several potential

productive hydrocarbon reservoirs have been encountered, the majority of the reserves appear to be contained in the Avalon and Hibernia sands. The development strategy considered in this report assumes that the Avalon and Hibernia reservoirs will be the only major reservoirs developed. The important parameters of these two reservoirs are reviewed in the following sections. The reserve estimates and development concepts presented are based on the Petroleum Directorate's interpretation of the available data.

2.2 Avalon Reservoir

2.2.1 General

The Avalon reservoir is bound on the north west and north east by major faults. The oil bearing sands appear to thin toward the south east and extension to the south west is limited by the presence of an aquifer. Faulting is apparent throughout the reservoir; however, the degree to which faulting affects communication is difficult to determine at this time.

Shallow marine sandstones comprise most of the Avalon reservoir. Although the areal extent is estimated to be 71.6 km^2, most of the hydrocarbon reserves are contained in an area approximately equal to 36.8 km^2.

2.2.2 Hydrocarbon Reserves and Reservoir Parameters

Reserves for the Avalon reservoir were estimated for three cases: low, medium and high. Each of these reserve categories as well as the associated reservoir parameters is shown in Table 2:1. The best estimate of reserves is contained in the medium case. The low case assumes a 25 percent reduction in the reservoir pore volume. The high case accounts for any possible extension of the reservoir.

Because of the uncertainty of the aquifer in maintaining reservoir pressure, it is assumed that a pressure maintenance scheme would be employed in the early stages of production. The recovery factor is about average for a sandstone reservoir under waterflood; however, this factor can be influenced by such considerations as production strategy, production facilities, economics or the physical limitations of the reservoir itself.

2.2.3 Well Spacing and Productivity

Initial indications are that a well spacing of 130 ha would be sufficient to deplete the hydrocarbon reserves. The average productivity of each well is assumed to be 1192 m^3 per day, with some wells capable of producing in the order of 3180 m^3 per day. Decreased well spacing may be required if the drainage characteristics of the reservoir are not as good as originally expected. The opposite may hold in the case of improved drainage.

2.3 Hibernia Reservoir

2.3.1 General

Similar to the Avalon reservoir, the Hibernia reservoir is bound on the north west and north east by major faults. The extension of the hydrocarbon zone to the south west and south east is limited by an aquifer. Faulting has resulted in the formation of two main hydrocarbon bearing areas, the B-08 and the P-15 fault blocks. As is the case in the Avalon reservoir, communication between these areas may be disrupted by faulting.

The fluid system and depositional environment of the Hibernia reservoir appear to be much more complex than those of the Avalon reservoir. The channel nature of the Hibernia sands may lead to poor reservoir continuity. It is difficult to determine the areal extent of the individual sands or the degree of communication between adjacent sands. In addition, the fluid systems of the

TABLE 2:1

Avalon Reservoir
Reserve and Reservoir Parameters
Summary

	Reservoir Category		
	Low	Medium	High
Approximate Depth (m)	2367	2367	2367
Reservoir Pressure (kpa)	24821	24821	24821
Reservoir Temperature (^{o}C)	65.6	65.6	65.6
Oil Gravity (^{o} API)	30.5	30.5	30.5
Porosity (Percent)	19	22	22
Water Saturation (Percent)	25	25	25
Areal Extent (E+06 m^2)	36.8	36.8	48.0
Average net pay (m)	106.1	122.1	119.8
Formation volume factor (rm^3/s m^3)	1.305	1.305	1.305
Initial oil in place (E+06 m^3)	426.4	568.5	727.2
Solution gas oil ratio (m^3/m^3)	104.7	104.7	104.7
Initial solution gas in place (E+06 m^3)	44644	59522	76124
Recovery Factor (Percent)	28	28	28
Recoverable Oil Reserves (E+06 m^3)	119.4	159.2	203.6

B-08 and P-15 fault blocks appear to be different. While the P-15 fault block contains an undersaturated oil, analysis of fluid samples from the B-08 fault block indicates that the reservoir is at saturation conditions and contains a gas cap.

2.3.2 Hydrocarbon Reserves and Reservoir Parameters

The reserves of the Hibernia reservoir were determined by the same method as those for the Avalon reservoir. These reserves, along with the associated reservoir parameters, are summarized in Table 2:2. The parameters are average values from the P-15 and B-08 wells. Communication throughout the reservoir is assumed to be continuous and not affected by the depositional environment or faulting. It is also assumed that a pressure maintenance scheme would be employed at the initiation of production. Higher oil recoveries are expected from the Hibernia reservoir due to the better quality reservoir and the favourable mobility ratios for secondary recovery. Again, it must be stressed that if communication across the reservoir is disrupted due to permeability barriers, the recovery factor may be reduced.

2.3.3 Well Spacing and Productivity

Although the main potentially productive area of the Hibernia reservoir has a greater areal extent than the Avalon reservoir, fewer wells are expected to be required. A well spacing of 260 ha is thought to be sufficient to deplete the hydrocarbon reserves. Average productivity per well is expected to be 1192 m^3 per day, with some wells capable of producing up to 4770 m^3 per day.

2.4 Field Development

The development strategy employed for Hibernia could set the trends for future transportation and development systems ultimately used in the area. Although emphasis here is placed on the use of fixed gravity based production platforms, other alternatives such as mobile or floating platforms, or a combination of both, are also being analyzed.

Figure 1 illustrates a development configuration for the Hibernia field using fixed gravity based production platforms with isolated templates tied to the platforms via seabed flowlines. As can be seen it is assumed that two fixed concrete units will be required to develop the Hibernia field. This assumption is based on current estimates of the reservoir size and productivity. Depending on the findings of additional delineation wells to be drilled in 1983, this assumption may change. If estimates of the reservoir size and productivity decrease, than this may mean that only one unit will be required. Likewise, a large increase in these estimates could cause an increase in the number of units required.

Since the number of development wells necessary to deplete a reservoir is relatively insensitive to the production method employed, the presentation of drilling forecasts for alternative development schemes would be repetitious and therefore would not yield much new information. It is for this reason that drilling associated with the alternative production methods has not been dealt with in this report.

The expected direct economic impact of the construction, fabrication and installation activities associated with the various production concepts will be addressed in our second planning report. This report is scheduled for release in early 1983 and is entitled, "Direct Economic Impact of Construction, Fabrication and Installation Activity Associated with the Hibernia Development".

TABLE 2:2

Hibernia Reservoir
Reserve and Reservoir Parameters
Summary

	Reservoir Category		
	Low	Medium	High
Approximate Depth (m)	3839	3839	3839
Reservoir Pressure (kpa)	39990	39990	39990
Reservoir Temperature (^{o}C)	121.1	121.1	121.1
Oil Gravity (^{o} API)	36	36	36
Porosity Percent	16	18	18
Water Saturation (Percent)	14	14	14
Areal Extent (E+06 m^2)	49.9	49.9	65.0
Average net pay (m)-oil	44.1	54.6	50.9
-gas	42.5	49.3	48.1
Formation volume factor (rm^3/s m^3)	1.9	1.9	1.9
Initial oil in place (E+06 m^3)	123.7	165.0	212.5
Solution Gas oil ratio (m^3/m^3)	285.1	285.1	285.1
Gas Compressibility Factor (Reservoir Conditions	1.07	1.07	1.07
Initial Gas in Place (E+06 m^3)-Solution	35273	47039	60571
-Associated	26061	34764	48888
Recovery Factor (Percent)	52.0	52.0	47.7
Recoverable Oil Reserves E+06 m^3	64.3	85.8	101.3

HIBERNIA FIELD DEVELOPMENT
—GRAVITY BASED SYSTEM—

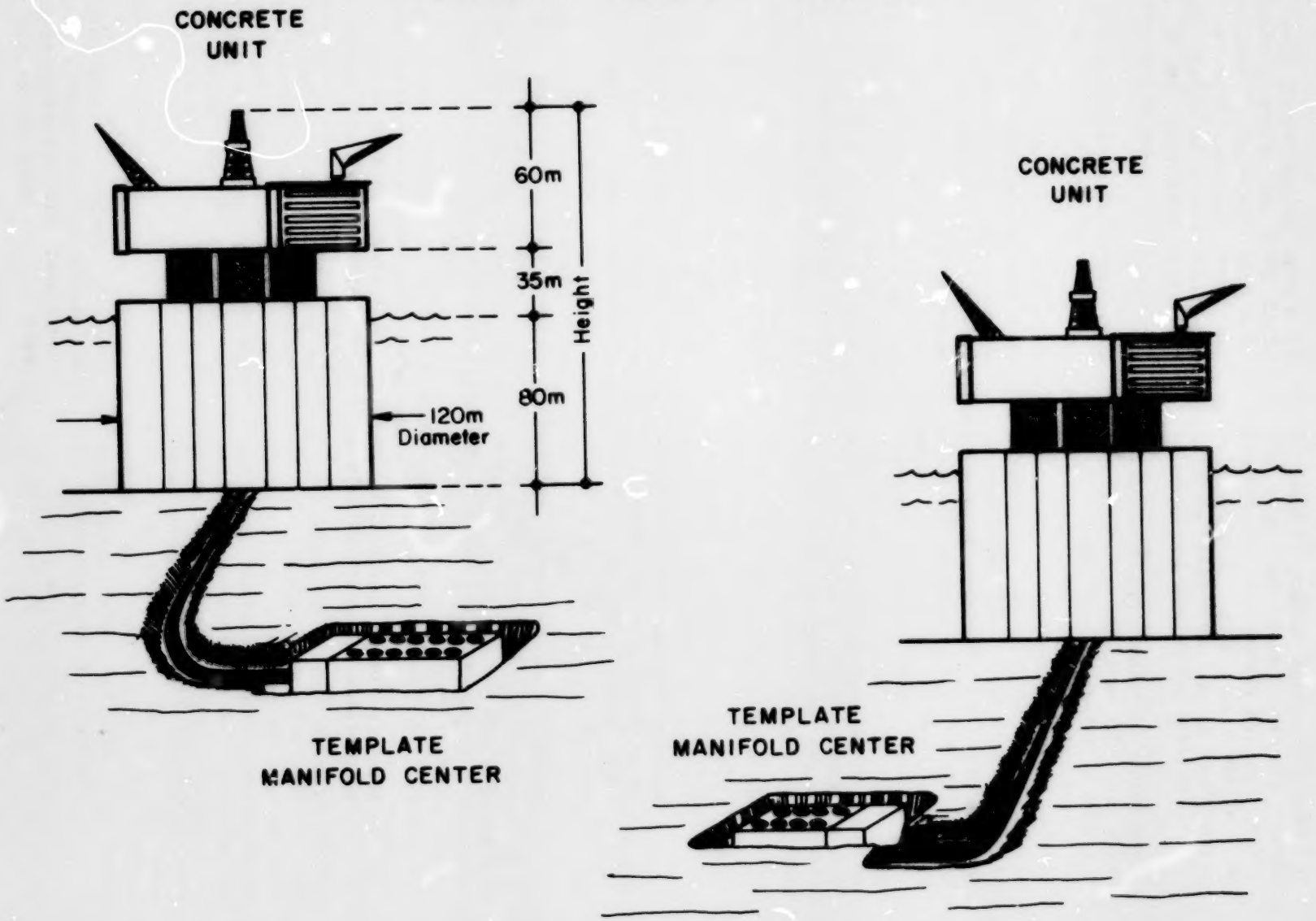


FIGURE 1

3. Forecasts of Drilling Activity

3.1 Introduction

The previous direct economic impact report dealt with the impact of seismic and drilling activity associated with the exploration phase of offshore oil and gas operations for the period 1981-1990. In that study, forecasts were made of the number of line kilometers of seismic surveys expected to be shot and the number of exploratory wells expected to be drilled under three different economic political operating environments.

This chapter presents revised estimates of the exploratory drilling data base used in the previous report and extends the analysis to include the delineation and development well programs that could occur during the 1982-1990 period.

It should be noted that although the low and high exploration forecasts represent what is believed to be reasonable lower and upper limits for exploration drilling, the ranges for delineation and development drilling only reflect the increased number of showings and commercial discoveries that result from the increased number of exploration wells. Sensitivity around the probability of a discovery or the number of wells per discovery has not been conducted.

The general forecasting methodology employed is to apply a highly generalized geological play analysis to the exploratory drilling forecasts in order to generate estimates of the number of showings and commercial discoveries. By applying a series of assumptions on the size distribution of reserves, the number of delineation wells per showing or commercial discovery, and the relationship between reserve size and the development well drilling program, a series of forecasted delineation and development drilling activity is presented.

It is recognized that this exercise is extremely hypothetical and involves a very large degree of uncertainty that increases both with time and with the stage of drilling activity modelled. Notwithstanding this, it is believed that the forecasting methodology developed outlines a realistic interaction of exploration, delineation and development drilling activity and that the range of estimates used gives our model enough flexibility and scope to capture the limits of reasonably expected economic impacts.

3.2 Drilling Program

3.2.1 Exploration Drilling

Table 3:1 represents the low, medium and high forecasts of exploratory well drilling for the four geological provinces illustrated in Figure 2. These forecasts represent revised estimates of the "FEP", "LOW" and "HIGH" forecasts of the previously mentioned impact report. The revisions reflect changes to the National Energy Program as well as the additional knowledge gained by the 1981 drilling program. The offshore drilling report for 1981 is presented in Table 3:2.

The range of 65 to 335 for the total number of exploration wells in the 1982-1990 period emphasizes the high degree of uncertainty inherent in any socioeconomic planning exercise associated with the oil and gas industry. As this exploration forecast forms the basis of our geological play analysis, this 5 times range of estimates becomes a major determining factor in the assessed economic impacts of the total offshore drilling program.

3.2.2 Delineation Drilling

If an exploratory well encounters significant quantities of hydrocarbons, a number of appraisal or delineation wells are drilled in order

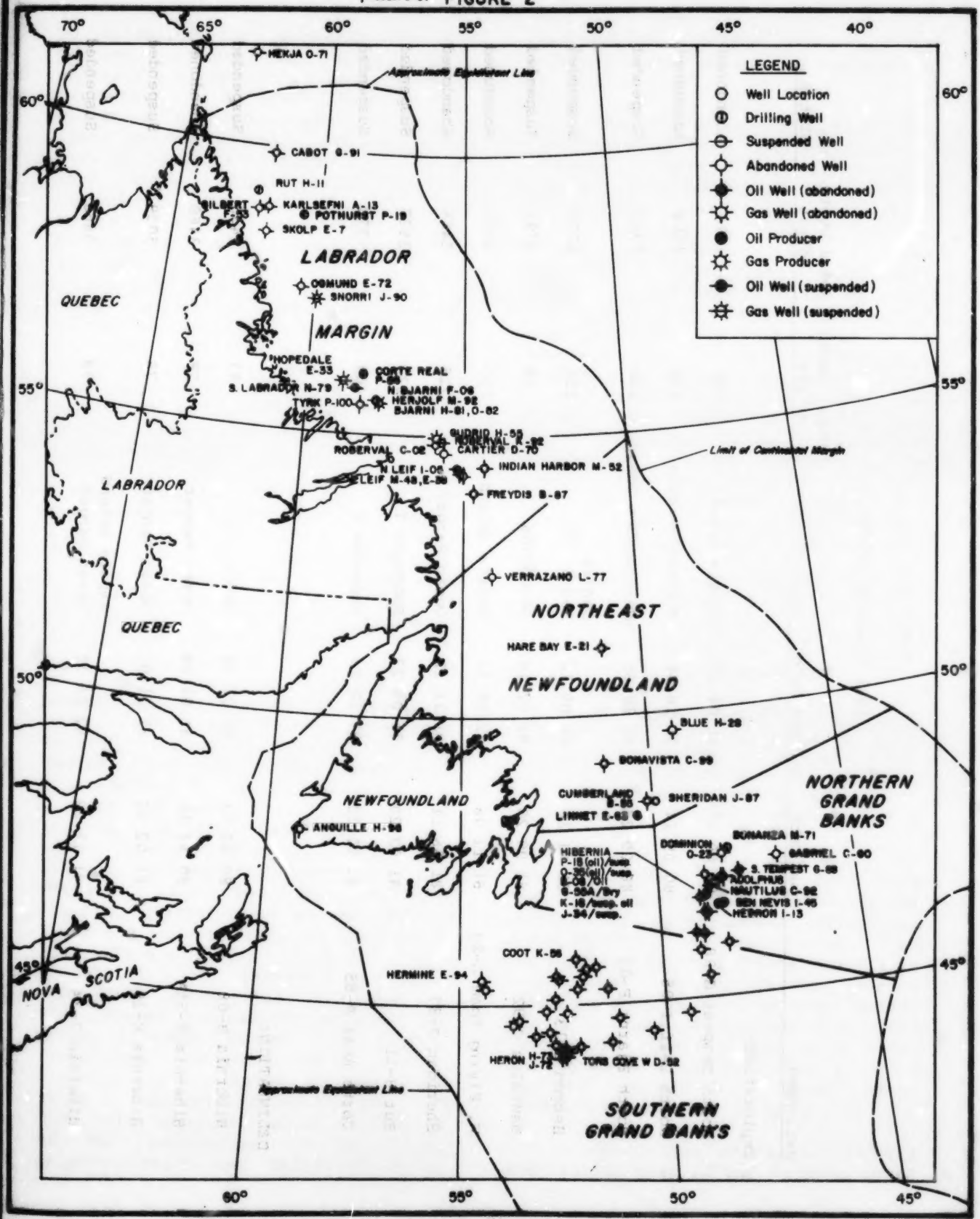
TABLE 3:1

Forecast of Exploration Wells
1982-1990

Year	Labrador Margin			Northeast Newfoundland			Northern Grand Banks			Southern Grand Banks			Total		
	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High
1982	4	4	4	1	1	1	3	3	3	0	0	0	8	8	8
1983	2	4	6	1	2	3	4	6	8	0	0	1	7	12	18
1984	2	4	7	1	2	5	4	9	15	0	1	2	7	16	29
1985	2	4	8	1	2	5	4	12	20	1	1	2	8	19	35
1986	2	4	9	1	3	6	5	13	25	1	2	2	9	22	42
1987	1	4	9	0	3	7	5	14	28	1	2	3	7	23	47
1988	1	4	9	0	3	8	6	15	30	1	2	4	8	24	51
1989	1	4	9	0	3	10	5	12	28	0	2	5	6	21	52
1990	1	4	9	0	3	12	4	10	27	0	2	5	5	19	53
TOTAL	16	36	70	5	22	57	40	94	184	4	12	24	65	164	335

Data presented for 1982 include wells spudded in 1981 but which had a significant amount of work performed on them in 1982.

FIGURE 2



WELL LOCATIONS

TABLE 3:2

1981 Drilling Report

Well Name	Spud Date	Release Date	Drilling Unit	Water Depth Meters	Total Depth Meters	Status
Exploration:						
South Tempest G-88	80 09 16	81 04 28	Zapata Ugland	156	4674	Abandoned
North Leif I-05	80 09 14	81 10 06	Pelican/Pelerin	146	3513	Abandoned
North Bjarni F-06	80 09 27	81 10 06	Pelican/Ben Ocean	150	2812	Suspended
Hebron I-13	81 01 14	81 09 12	Lancer Sedco 706	121	4724	Suspended
Nautulus C-92	81 09 29	82 07 16	Sedco 706	84	5791	Suspended
W. Flying Foam L-23	81 11 08	82 05 11	Zapata Ugland	95	4877	Abandoned
Sheridan J-87	81 06 11	81 11 22	Ocean Ranger	215	5486	Abandoned
Rut H-11	81 07 20	81 09 27	Pacnorse I	124	3527	Suspended
Corte Real P-85	81 10 02	81 10 13	Pacnorse I	469	770	Suspended
DELINEATION:						
Hibernia B-08	80 03 13	81 01 06	Sedco 706	83	4436	Suspended
Hibernia G-55A	80 12 11	81 02 24	Ocean Ranger	78	3460	Abandoned
Hibernia K-18	81 02 26	81 11 05	Ocean Ranger/	78	5039	Suspended
Hibernia J-34	81 11 29	82 06 15	Zapata Ugland Ocean Ranger	78	3865	Suspended

to determine the potential of the formation encountered. These wells enable the estimation of such valuable parameters as, the areal extent of the reservoir, the amount of petroleum in place and the amount of the resource that is ultimately recoverable. This information is invaluable in helping the operator determine the number and location of the development wells necessary for optimal depletion of the reservoir.

The activities associated with delineation drilling are very similar to those associated with exploration drilling. With the exception of an increased number of testing days for delineation wells, both well types are treated identically in our economic impact models.

The remainder of this section describes the methodology employed to establish the delineation well forecasts for the period 1982-1990. At the outset, success ratios were applied to the exploration forecasts of Table 3:1 and the 1981 exploration drilling program highlighted in Table 3:2. The particular ratios applied to a given exploration program vary widely and are primarily dependent upon the particular operators understanding of the geology and the degree to which the geological characteristics vary within the exploration area. The probability of success also varies significantly with time. This temporal variation reflects a learning curve for the operator that has two separate aspects. Firstly, as an exploration program continues with no commercial discoveries being found, the probability of gaining subsequent commercial discoveries decreases as the initial exploration efforts are often directed toward the largest structures. The second aspect of this learning curve reflects the case where after a commercial discovery has been made, the operator has an indication of the combination of geological characteristics most often associated with commercial discoveries and as such can better direct his exploration efforts.

For the purpose of this study, the success ratios have been expressed to reflect the possibility of having a showing or a commercial discovery of hydrocarbons within any exploration well. A showing refers to an exploration well that shows hydrocarbon potential significant enough to warrant the drilling of a single delineation well in the second year following, and then proves to be noncommercial. A commercial discovery, for the purpose of this report, refers to any field that when viewed in isolation and upon completion of the prescribed delineation program proves to be commercial under conditions at the time of development. Table 3:3 presents the assumed required number of delineation wells for various reserve sizes.

TABLE 3:3
Delineation Wells as a
Function of Reserve Size

Recoverable Reserves	Wells
Showing	1
$\leq$ 750 mmbls	4
$>$ 750 mmbls but $\leq$ 1000 mmbls	6
$>$1000 mmbls but $\leq$ 2000 mmbls	8

The success ratios applied to the four geological provinces have been varied in order to reflect the various drilling histories and the geological knowledge that has been gained. This assumption, which is consistent with previously discussed reasons for a temporal variation of success ratios, yields a range of success ratios for hydrocarbon showings from 1 in 3 for the northern Grand Banks to 1 in 25 for the southern Grand Banks. These ratios are contained in Table 3:4.

In recognition of the anticipated exploration play in the northern Grand

Banks, it was considered necessary to vary the success ratios within the forecast period. As shown in Table 3:4, these ratios yield a success ratio for showings varying from an anticipated actual of 1 in 3 for 1982 to an assumed ratio of 1 in 20 for 1989 and 1990.

Table 3:4
Exploration Success Ratios

Region	Showings to Exploration Wells
South Grand Banks	1 in 25
North Grand Banks	*
North East Nfld	1 in 20
Labrador Margin	1 in 10
1982	1 in 3
1983	1 in 5
1984	1 in 10
1985	1 in 10
1986	1 in 10
1987	1 in 15
1988	1 in 15
1989	1 in 20
1990	1 in 20

Application of the success ratios presented in Table 3:4 to the exploration well forecasts gives the forecasts of showings, for 1982-1990, as presented in Table 3:5. Based upon what is currently known about the geology of the four areas under study it appears that the Labrador Margin and the northeast Newfoundland Basin are gas prone while discoveries in the northern Grand Banks and southern Grand Banks are more likely to contain oil. Although evidence exists to suggest the possibility of the discovery of commercial quantities of oil in the Labrador Margin or northeast Newfoundland Basin, knowledge about the geology of the four areas suggests that the northeast Newfoundland Basin and the Labrador Margin are gas prone while the northern Grand Banks or southern Grand Banks are more likely to contain oil.

To reduce the number of variables in our forecast to a manageable number, potential gas discoveries in the northern or southern Grand Banks or oil discoveries in the Labrador Margin or the northeast Newfoundland Basin have not been considered.

To reflect the various engineering constraints and the relative economics of gas, it is assumed that the discoveries to showings ratio for gas is 1 in 10 for the Labrador Margin and 1 in 5 for the northeast Newfoundland Basin. For the remaining two areas, the northern Grand Banks and the southern Grand Banks, the commercial discoveries to showings ratios are set at 1 in 2 and 1 in 5, respectively.

The above assumptions imply that the only area to experience commercial discoveries over the next ten years will be the northern Grand Banks. Changes in technology or the discovery of very large reserves could invalidate this assumption. Table 3:6 presents forecasts of commercial discoveries for the period 1982-1990.

TABLE 3:6
Forecasts of Commercial Discoveries
1982-1990

Year	Low	Medium	High
1982	0	0	0
1983	0	1	1
1984	1	0	0
1985	0	0	1
1986	0	1	1
1987	0	1	1
1988	0	0	1
1989	1	0	0
1990	0	1	1
TOTAL	2	4	6

It should be noted that, of the four wells worked on in 1981, one has been assumed to be a showing and one to be a commercial discovery.

TABLE 3:5

Forecast of Showings
1982-1990

Year	Labrador Margin			Northeast Newfoundland			Northern Grand Banks			Southern Grand Banks			Total		
	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High
1982	0	0	0	0	0	0	1	1	1	0	0	0	1	1	1
1983	0	0	0	0	0	0	0	1	1	0	0	0	0	1	1
1984	0	1	1	0	0	0	1	0	1	0	0	0	1	1	2
1985	0	0	1	0	0	0	0	1	2	0	0	0	0	1	3
1986	1	0	1	0	0	1	0	1	2	0	0	0	1	1	4
1987	0	1	1	0	0	0	1	2	1	0	0	0	1	3	2
1988	0	0	1	0	0	0	0	1	2	0	0	0	0	1	3
1989	0	1	1	0	1	1	1	0	1	0	0	0	1	2	3
'990	0	0	0	0	0	0	0	1	1	0	0	0	0	1	1
TOTAL	1	3	6	0	1	2	4	8	12	0	0	0	5	12	20

From Tables 3:3, 3:5 and 3:6, low, medium and high forecasts of delineation wells are made. These drilling programs are broken out by year and by geological region and are presented in Table 3:7. As is expected, the main delineation well activity is located in the areas of greatest exploration activity, with the total forecasted delineation drilling program ranging from a low of 19 wells to a high of 46.

The principal assumptions that were used in the derivation of the forecasts contained in Table 3:7 are listed below.

1. Every showing calls for one delineation well to be drilled in the second year following

2. Every commercial discovery calls for a delineation program consistent with Table 3:3

3. The delineation program for commercial discoveries is conducted over a two year period beginning in the year immediately following the discovery.

The assumptions outlined above represent the author's views of the expected delineation well programs in light of such considerations as the Hibernia and North Sea experiences and the given environmental and economic constraints.

3.2.3 Development Drilling

3.2.3.1 Introduction

Development drilling as defined in this report includes all drilling activity associated with the field development stage of an offshore oil and gas discovery. As such it includes all producing wells, water injector wells and gas injector wells. Dry holes resulting from development drilling operations are also included. The drilling programs presented are restricted to the primary and secondary recovery stages and do not include any wells that are subsequently drilled on an infill drilling program.

3.2.3.2 Development Drilling for Hibernia

The Petroleum Directorate's most likely (medium case) estimate of the number of development wells necessary to effectively drain the Hibernia field is presented in Table 3:8. It is assumed that all producing wells and gas injector wells are directionally drilled with water injectors being vertically drilled and connected to the production platforms via seabed flowlines. Figures for dry holes were derived by assuming that 10 percent of the wells in either the vertically or directionally drilled categories will either fail to hit their target or will experience technical difficulties. It should be noted that the well forecasts contained in Table 3:8 are based on the medium estimate of wells for the medium reserves case of chapter 2 and do not consider variations in such parameters as well productivity, well spacing and the areal extent of the reservoirs.

The distribution of deviation angles for the medium development drilling forecast for the Hibernia field, excluding all dry holes and vertically drilled wells, is presented in Table 3:9.

TABLE 3:9

Maximum Drilling Angle Distribution
- Hibernia Field -

Deviation Angles Range	Median	Wells	% of Total
0° - 10°	5°	2	3.0
11° - 20°	15°	6	11.0
21° - 30°	25°	13	23.0
31° - 40°	35°	11	20.0
41° - 50°	45°	13	23.0
>50°	55°	11	20.0
		56	100.0

TABLE 3:7

Forecast of Delineation Wells
1982-1990

Year	Labrador Margin			Northeast Newfoundland			Northern Grand Banks			Southern Grand Banks			Total		
	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High
1982	0	0	0	0	0	0	1	1	1	0	0	0	1	1	1
1983	0	0	0	0	0	0	3	3	3	0	0	0	3	3	3
1984	0	0	0	0	0	0	4	6	6	0	0	0	4	6	6
1985	0	0	0	0	0	0	4	4	4	0	0	0	4	4	4
1986	0	1	1	0	0	0	2	0	4	0	0	0	2	1	5
1987	0	0	1	0	0	0	0	4	6	0	0	0	0	4	7
1988	1	0	1	0	0	1	0	5	5	0	0	0	1	5	7
1989	0	1	1	0	0	0	1	3	6	0	0	0	1	4	7
1990	0	0	1	0	0	0	3	1	5	0	0	0	3	1	6
TOTAL	1	2	5	0	0	1	18	27	40	0	0	0	19	29	46

TABLE 3:8

Forecast of Development Drilling for Hibernia
(Medium Case)

Number of Wells					
	Injectors		Dry Holes		
Producers	Vertical	Directional	Vertical	Directional	Total
52	17	4	2	6	81

Note: As discussed previously these figures are for the medium case. Preliminary indications are that the actual number of wells could range from 50 to 110.

This deviation angle distribution was taken as representative of all offshore Newfoundland development drilling programs and as such was used to yield the vertical depth/horizontal offset information for all subsequent discoveries.

Figure 3 presents a schematic representation of the drilling and construction activity associated with the Hibernia development. This figure is based upon the medium estimate of reserves, the medium development drilling program and the medium template forecast. As is evident from Figure 3, this report assumes that the Hibernia oil field will be developed with concrete gravity based platforms and as such the majority of the production wells will be drilled from these units. It is practical, however, to expect that isolated templates will be utilized in order to obtain production earlier and to provide access to the more remote areas of the reservoir. The wells associated with such templates will be drilled with the standard semisubmersible drilling rig. All isolated water injector wells will also be drilled with a semisubmersible rig.

As will be discussed in more detail in subsequent reports, the initiation of development drilling through a isolated template must be preceeded by the fabrication and installation of the template. Similarly where environmental conditions dictate, these templates must be placed in excavations in the sea floor (glory holes). Because of the environmentally dictated window for dredging activity, May to October, development drilling from a template that has to be located in a glory hole could not begin until late fall. For this reason and the desire to coordinate the template drilled wells with the installation of the fixed platforms, development drilling at Hibernia is assumed to start in late 1988 and late 1989 for wells associated with platform number one (Avalon Reservoir) and number two (Hibernia Reservoir), respectively. Drilling from the fixed units will commence as soon as these units are installed, i.e. early 1990 and early 1991.

Although Figure 3 represents a possible development drilling program for the Hibernia field, it must be stressed that diagrams of this sort are subject to many factors, such as, the date of development plan submission, subsea production component design, field layout of templates, number of wells per template, etc. No attempt has been made to model the effects of variations in any of these factors.

3.2.3.3 Development Drilling for Subsequent Fields

As discussed above, the determination of the number of development wells for a field already discovered is a difficult task. To estimate the required number of development wells for as yet undiscovered fields is even more difficult. The approach taken here involved four principal steps.

1. Determine the potential start dates of the various discoveries. These dates are determined on the basis of discovery date, delineation drilling program, development plan approval date, dredging/template installation and platform construction time.

2. Based upon recognized size-frequency distributions of offshore oil fields, assign a total recoverable reserves figure to a particular discovery.

3. Based upon statistical relationships between total recoverable reserves and total required wells, for offshore oil fields, generate projections of

HIBERNIA FIELD DEVELOPMENT - GRAVITY BASED SYSTEMS

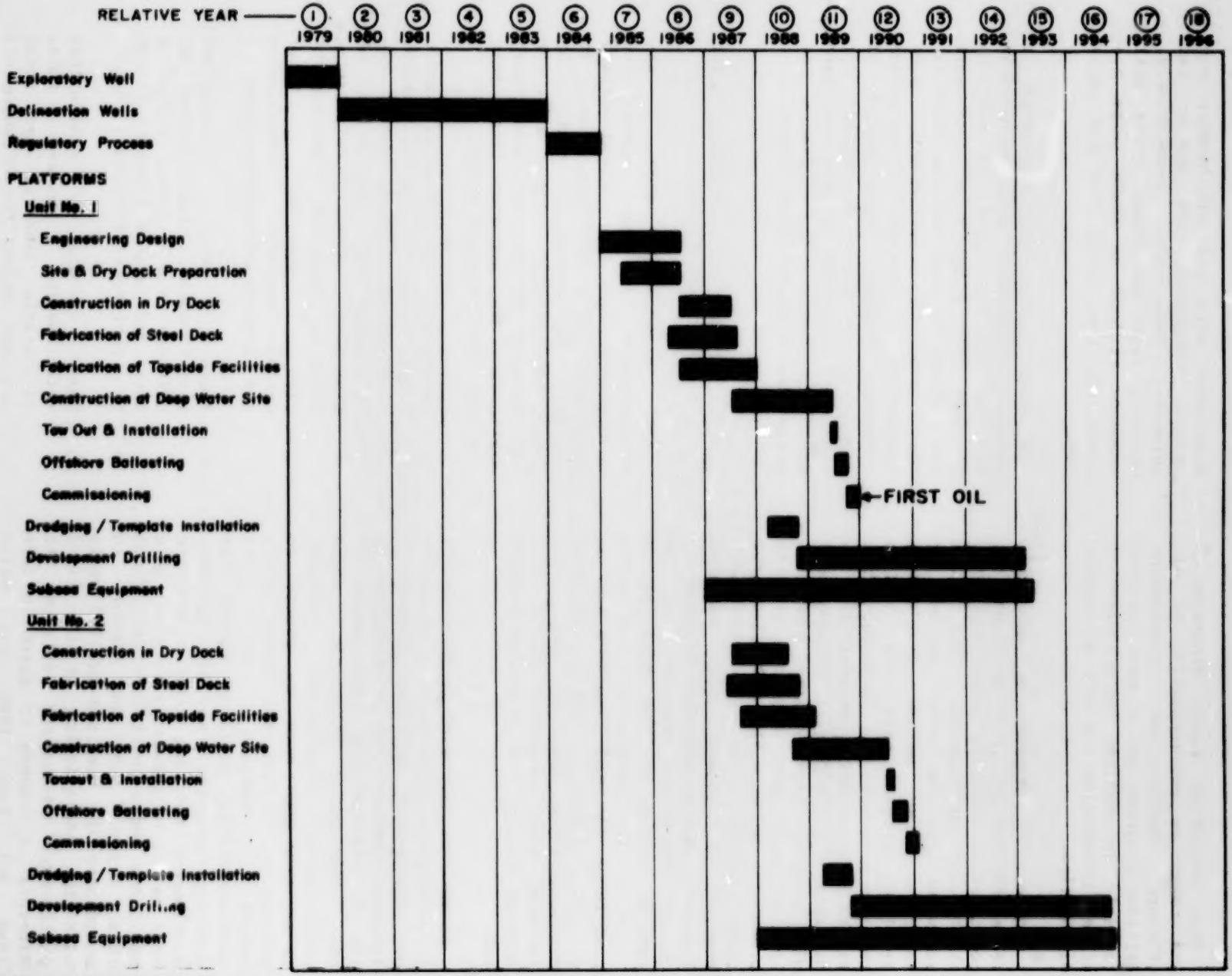


FIGURE 3

the required number of wells associated with the various reserve sizes.

4. Determine what percentage of the total required number of wells that will be directionally drilled and combine these wells into template groupings.

For the purpose of this offshore development drilling forecast, it was assumed that a development plan would be submitted in January of the year following the end of a two year delineation drilling program. Regulatory approval is assumed to take 9-12 months. Construction activity would begin in the summer of the following year and would continue for three and one half (3.5) to four and one half (4.5) years. The potential start dates for development drilling based upon the above assumptions are presented in Table 3:10.

In consideration of the Newfoundland and Labrador Petroleum Regulations, it is noted that, in this analysis, no attempt has been made to model the government's stated policy of sequencing offshore oil and gas developments within the same management zone. The terms of such a development sequence period are determinable by the Minister on the basis of such considerations as the future need of petroleum in Canada and the need for orderly economic and social development in the province.

The assignment of total recoverable reserves to each of the hypothetical discoveries was accomplished by the following methodology. Generally, it was recognized that the size-frequency distribution of oil fields of a given structural-stratigraphic type are log-normally distributed. Assuming that the exploration play on the northern Grand Banks will be based on a "Hibernia-type" structural model, a single log-normal statistical distribution was adopted for this report.

The size-frequency distribution of the total recoverable reserves per field and the total discovered reserves for the forecast cases are within reasonable estimates of the total hydrocarbon resource potential of the northern Grand Banks as estimated by the Petroleum Directorate through Monte Carlo simulation techniques.

Determining the total number of wells required to effectively drain the reserves outlined in Table 3:10 was approached through a statistical analysis of the field development plans for the North Sea and Hibernia developments.

Figure 4 represents a least squares linear regression solution of total development wells versus total recoverable reserves per field size. It is recognized that the equation for development well requirements is not a direct function of recoverable reserves but rather is dependent upon many other variables such as areal extent, porosities, net pay, and, depending on the range of reserves studied, may not even be linear. Given the scope of this forecasting exercise and the previously stated assumption that all predicted discoveries are based upon a "Hibernia type" structural model, it is felt that the solution chosen is adequate. A minimum value of 500 million barrels of recoverable reserves has been chosen on the basis of past project evaluation studies that have shown that a field of 500 million barrels, in the Newfoundland offshore, is marginally economic to subeconomic within a reasonable range of pricing and cost assumptions.

Since the current medium estimate of development drilling for Hibernia falls on the regression line of Figure 4 it is assumed that this line will yield the medium estimate of the development drilling requirements for the forecasted discoveries.

TABLE 3:10

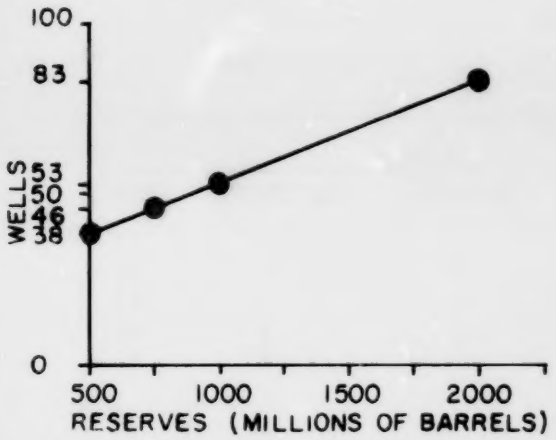
Size and Timing Statistics for
Northern Grand Banks Discovered Oil Fields

Forecast Case	Field Name	Discovery Date	Development Drilling Start Date	Recoverable Reserves
LOW	Hibernia*	1979	1988	1650 MMBLS
	Hypo 1*	1981	1990	500 MMBLS
	Hypo 2	1984	1991	750 MMBLS
	Hypo 3	1989	1995	1000 MMBLS
MEDIUM	Hibernia*	1979	1988	1650 MMBLS
	Hypo 1*	1981	1990	500 MMBLS
	Hypo 2	1983	1990	750 MMBLS
	Hypo 3	1986	1992	1000 MMBLS
	Hypo 4	1987	1993	750 MMBLS
	Hypo 5	1990	1996	500 MMBLS
HIGH	Hibernia*	1979	1988	1650 MMBLS
	Hypo 1*	1981	1990	500 MMBLS
	Hypo 2	1983	1990	750 MMBLS
	Hypo 3	1985	1991	1000 MMBLS
	Hypo 4	1986	1992	750 MMBLS
	Hypo 5	1987	1993	500 MMBLS
	Hypo 6	1988	1994	2000 MMBLS
	Hypo 7	1990	1996	500 MMBLS

* The assumed hypothetical (Hypo) 500 million barrel discovery in 1981 and the Hibernia discovery of 1979 do not follow the schedule of events described previously. Hibernia is taking a relatively long time because it is a new discovery in a new area and as such much original research and development must be conducted. The hypothetical 500 million barrel field is assumed to have been discovered as a result of the 1981 drilling program. Because of Mobil's involvement with Hibernia, delineation of this field is assumed to be delayed by two years.

FIGURE 4

Relationship between Development Wells and Field Size - UK North Sea



The final step in preparing the development well forecasts is to divide the total well requirements identified in Figure 4 into producing wells and injector wells. From the Petroleum Directorate's reservoir simulation studies and the North Sea experience, it appears that approximately 30 percent of the total wells required for the Hibernia field will be injector wells and that 20 percent of these injector wells will be gas while water injectors will make up the remaining 80 percent. Again using a "Hibernia-type" reservoir model, which is based on central gas injection and peripheral water injection, it was assumed that all of the producers and gas injectors are directionally drilled while the water injectors are vertically drilled. It was further assumed that 10 percent of each of these well classifications would result as dry holes. These dry hole figures are added to the total producers and injectors to obtain the total number of wells required for each reservoir size. These data are presented in Table 3:11.

It is realized that this forecasting approach involves extremely hypothetical generalizations; however, it is felt that the range presented is sufficient to portray the probable range of drilling requirements expected for a "Hibernia-type" reservoir containing between 500 and 2000 million barrels of recoverable reserves. Based upon these assumptions the forecasted number of development wells per year in the 1982-1990 period is presented in Table 3:12.

3.2.4 Total Drilling Activity

Grouping of the three delineation and development drilling forecasts with the associated exploratory drilling forecasts allows assessment of the total direct impact of offshore drilling activity. Figure 5 illustrates the total activity forecasted. To indicate the relative magnitude of these forecasts, the actual drilling activity experienced in the United Kingdom sector of the North Sea is also presented. It appears that the development drilling activity to be expected in Newfoundland's offshore area will be much less than that experienced in the North Sea. This is because of the planning period selected. If the planning horizon were extended, one would see that development drilling alone would account for 233, 326 and 460 wells under the low, medium and high discovery cases, respectively. Figure 6 and Table 3:13 show the UK North Sea actuals on an annual basis for each well classification considered. Figure 7 presents the total offshore Newfoundland and Labrador drilling activity (actuals for 1981 and forecasts for 1982-1990) on an annual basis for the low, medium and high cases.

TABLE 3:11

Development Well Requirements
By Reservoir Size

Reserve Size (MMBLS)	Number of Templates	Wells			
		Producers	Injectors	Dry Holes	Total
500	2	27	11	4	42
750	3	33	13	5	51
1000	4	38	15	6	59
1650	5	52	21	8	81
2000	6	59	24	9	92

TABLE 3:12

Development Well Drilling Forecasts
- Offshore Newfoundland -

Year	Forecast Case		
	Low	Medium	High
1982	-	-	-
1983	-	-	-
1984	-	-	-
1985	-	-	-
1986	-	-	-
1987	-	-	-
1988	3	3	3
1989	11	11	11
1990	18	20	20
TOTAL	32	34	34

FIGURE 5

TOTAL DRILLING ACTIVITY

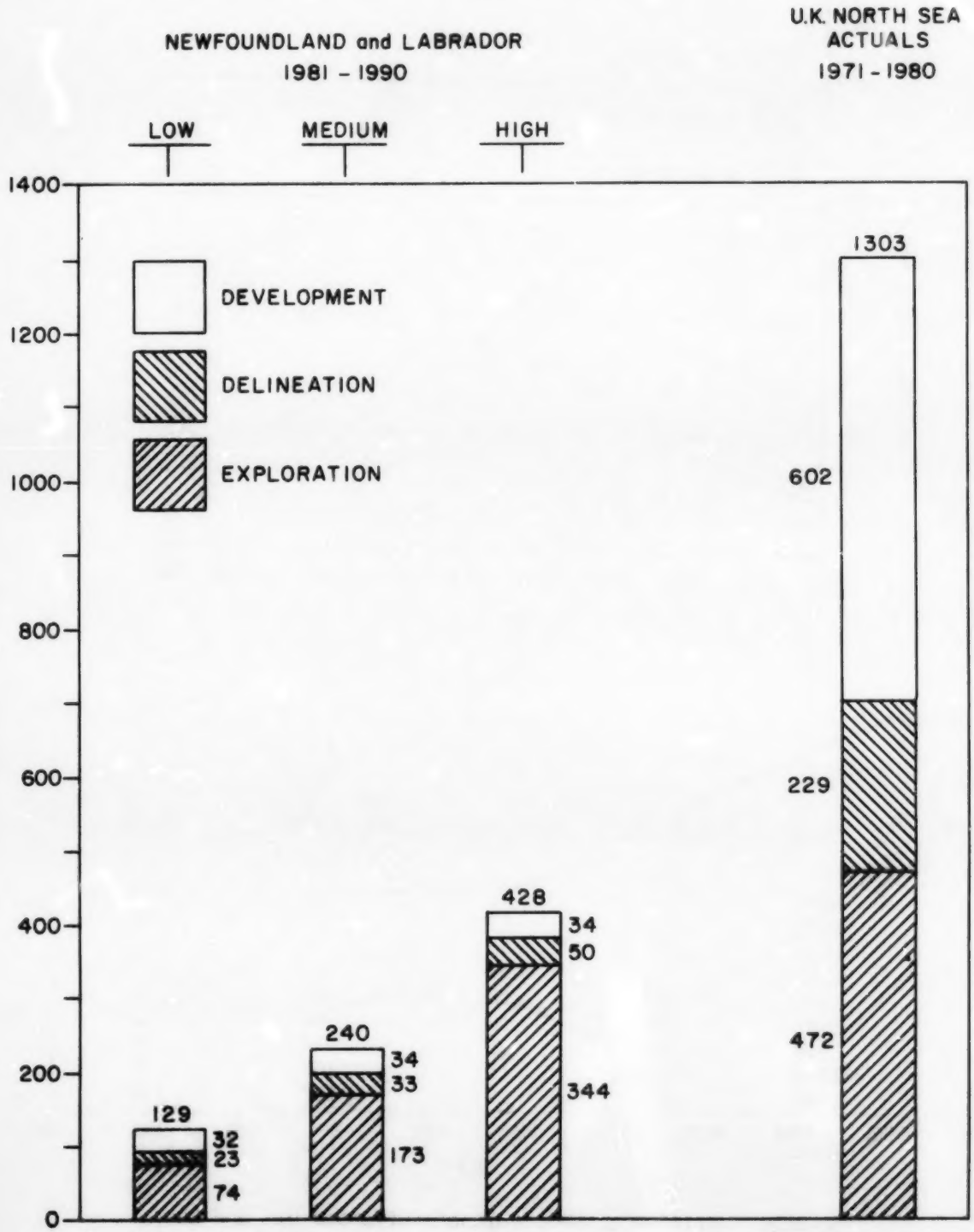


FIGURE 6

WELLS DRILLED- U.K. NORTH SEA

1971 - 1980

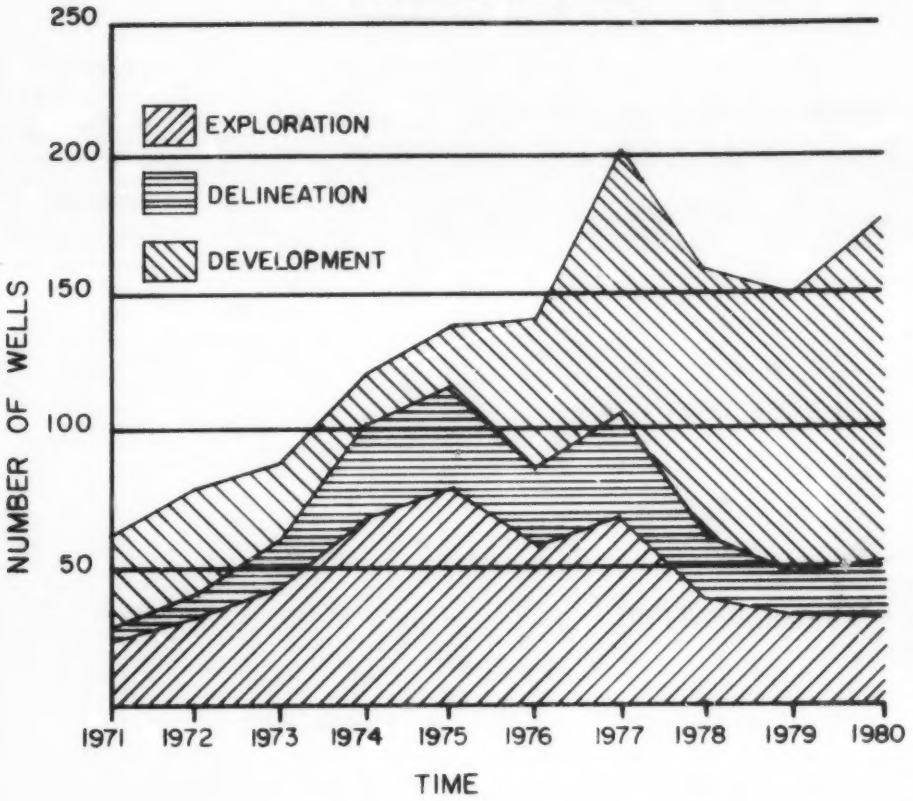


Table 5.7

Wells Drilled - U.K. North Sea
1971-1980

Year	Exploration	Delineation	Development	Total
1971	24	4	34	62
1972	33	8	36	77
1973	42	19	21	82
1974	67	33	20	120
1975	79	37	21	137
1976	58	28	54	140
1977	67	38	96	201
1978	37	25	96	158
1979	33	15	102	150
1980	32	22	122	176
Total	472	229	602	1303

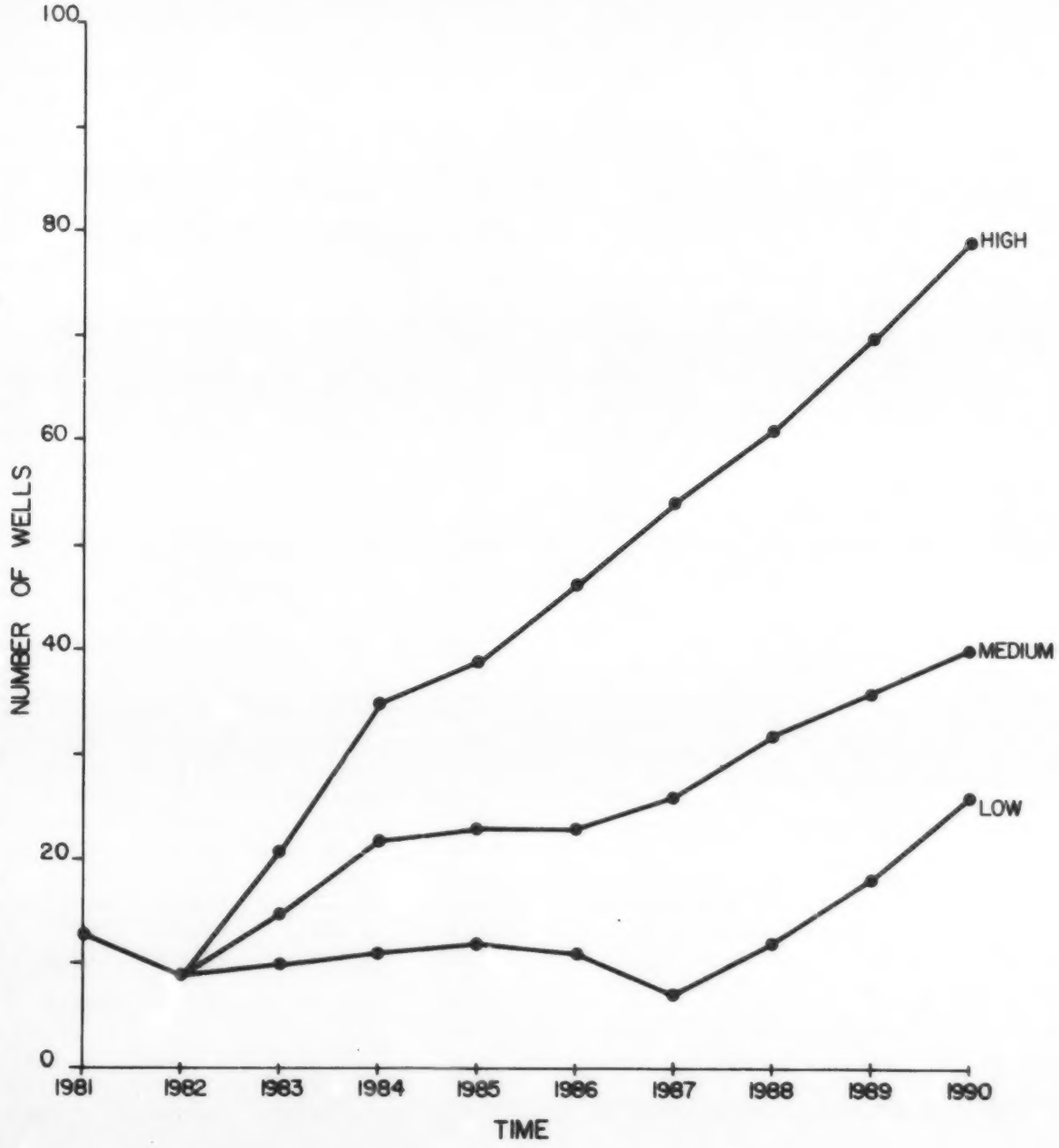
Source: William C. Uhl, Europe's Offshore Oil and Gas, William F. Bland Co., Connecticut, September 1981.

FIGURE 7

TOTAL WELLS

OFFSHORE NEWFOUNDLAND AND LABRADOR

1981-1990



4. Forecast of Economic Impact of Drilling Activity

4.1 Overview

Chapter three provided low, medium and high forecasts of exploration, delineation, and development drilling. Based upon these forecasts, this chapter provides detailed information on the quantities of goods and services, the expenditures by major expenditure category, and the manpower requirements in terms of onshore and offshore. A detailed description of each of these items can be found on pages 21 through 35 of "Economic Impact of Future Offshore Petroleum Exploration", May 1981.

It should be noted that since May, 1981, further development and refinement of our expenditure impact models has been accomplished. The most significant improvements have been the addition of the facilities necessary to calculate the goods and services, employment and expenditures associated with delineation and development drilling. One other noteworthy improvement has been to the procedure for calculating the rig requirements for a given drilling program. This refinement allows a more optimal allocation of rigs, thus decreasing the rig requirements forecasted. All revisions and improvements have been incorporated into the forecasts that are presented in the following sections.

4.2 Goods and Services

The goods and services consumed in connection with exploration, delineation, and development drilling have been divided into drilling rig days, supply boat days, helicopter days, the number of drilling rigs, the number of supply boats, the number of helicopters, the amount of cement, the amount of casing, the amount of fuel (marine and jet) and the amount of drilling fluid additives (barite, bentonite and all other additives). Low, medium and high forecasts of each of these 13 items are contained in Tables 4:1-4:10.

TABLE 4:1

Forecast of Drilling Rig Days

Year	Low	Medium	High
1982	985	985	985
1983	1273	1791	2512
1984	1547	2904	4456
1985	1816	3174	4918
1986	1436	2624	5777
1987	812	3067	6395
1988	1054	3363	6093
1989	1235	3111	6852
1990	1627	2873	7367
TOTAL	11785	23892	45355

TABLE 4:2

Forecast of Supply Boat Days

Year	Low	Medium	High
1982	2721	2721	2721
1983	3553	4993	7013
1984	4351	8127	12467
1985	5131	8914	13752
1986	4001	7268	16107
1987	2239	8451	17739
1988	2810	9189	16619
1989	3076	8254	18599
1990	3900	7250	19668
TOTAL	31782	65167	124685

TABLE 4:3

Forecast of Helicopter Days

Year	Low	Medium	High
1982	907	907	907
1983	1185	1665	2338
1984	1449	2708	4154
1985	1708	2968	4580
1986	1334	2422	5367
1987	746	2817	5911
1988	967	3092	5568
1989	1166	2890	6339
1990	1530	2671	6811
TOTAL	10992	22140	41975

TABLE 4:4

Forecast of Number of Drilling Rigs

Year	Low	Medium	High
1982	5	5	5
1983	6	8	12
1984	7	12	19
1985	8	13	21
1986	6	11	23
1987	3	13	26
1988	6	14	26
1989	5	13	27
1990	9	16	31

TABLE 4:5

Forecast of Number of Supply Boats

Year	Low	Medium	High
1982	15	15	15
1983	18	24	36
1984	21	36	57
1985	24	39	63
1986	18	33	69
1987	9	39	78
1988	17	41	77
1989	13	37	79
1990	22	42	87

TABLE 4:6

Forecast of Number of Helicopters

Year	Low	Medium	High
1982	5	5	5
1983	6	8	12
1984	7	12	19
1985	8	13	21
1986	6	11	23
1987	3	13	26
1988	6	14	26
1989	5	13	27
1990	9	16	31

TABLE 4:7

Forecast of Cement
(tonnes)

Year	Low	Medium	High
1982	2535.5	2535.5	2535.5
1983	2762.8	4188.9	6102.9
1984	3285.4	6384.6	10302.5
1985	3707.3	7047.5	11580.6
1986	3150.7	6391.0	13517.2
1987	1995.3	7331.7	15280.4
1988	2811.7	7760.4	15090.8
1989	3333.1	7874.8	16755.1
1990	3939.4	7508.5	17846.2
TOTAL	27521.2	57022.8	109011.2

TABLE 4:8

Forecast of Casing
(tonnes)

Year	Low	Medium	High
1982	3275.5	3275.5	3275.5
1983	3915.7	5704.4	8100.5
1984	4686.3	8923.0	13936.7
1985	5326.3	9615.7	15404.1
1986	4352.5	8336.2	18048.7
1987	2580.6	9838.4	20363.4
1988	3958.1	11028.2	20530.3
1989	5972.9	12078.9	23986.8
1990	7599.2	12118.3	26165.9
TOTAL	41667.1	80918.4	149811.8

TABLE 4:9

Forecast of Fuel
(tonnes)

Year	Marine			Jet		
	Low	Medium	High	Low	Medium	High
1982	55748.0	55748.0	55748.0	109[illegible]5	1093.5	1093.5
1983	55568.9	87878.9	128858.6	1344.[illegible]	2020.7	2851.5
1984	77973.2	139280.4	231109.4	2054.4	3575.1	5595.4
1985	86004.9	166225.9	258926.7	2212.6	4030.6	6093.1
1986	67648.7	136276.3	295186.8	1725.2	3417.8	7453.3
1987	49555.6	170512.1	354301.6	1206.7	4278.3	8779.6
1988	54218.8	170712.7	314067.5	1399.1	4528.4	7984.8
1989	56107.6	153472.4	332476.9	1552.6	3901.2	8368.8
1990	69448.4	136298.9	357107.6	1876.8	3320.9	9197.3
TOTAL	572294.2	1216404.0	2327781.0	14465.7	30166.4	57417.2

TABLE 4:10

Forecast of Drilling Fluid Additives
(tonnes)

Year	Barite			Bentonite			Other Additives		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
1982	5584.1	5584.1	5584.1	1294.0	1294.0	1294.0	1035 3	1035 3	1035.3
1983	11302.2	14600.3	19435.2	2599.1	3361.8	4479.9	1949.8	2549.7	3429.8
1984	13795.4	26202.5	39185.6	3175.5	6027.7	9016.7	2402.1	4535.4	6799.7
1985	11334.0	24419.1	40816.0	2607.1	5616.8	9391.3	1960.6	4222.4	7078.8
1986	11160.0	22692.1	48850.3	2565.5	5217.5	11233.4	1919.0	3908.2	8424.5
1987	7265.5	27570.2	57271.2	1670.7	6337.3	13171.1	1252.6	4736.4	9885.9
1988	10572.4	35452.1	66149.9	2438.8	8144.9	15205.4	1826.7	6006.7	11310.7
1989	13631.1	31041.8	69324.2	3157.2	7162.8	15955.4	2273.3	5289.7	11813.8
1990	15219.0	28777.1	70017.1	3531.8	6655.5	16127.8	2516.0	4865.9	11896.4
TOTAL	99863.5	216339.2	416633.6	23039.6	49818.2	95974.8	17135.4	37148.7	71674.9

4.3 Expenditures

The tabulation and publication of expenditures associated with any particular well program requires between one and two years. Because of this lag, it was necessary to use our expenditure impact model in order to calculate data for 1981. As time is the key variable in determining well costs, special attention is drawn to the prediction of rigdays. By inputting the actual distances drilled in 1981, the estimate of 1200 rig days was obtained. This number is comprised of 104 days of mobilization and demobilization activity and 1096 days on site. A comparison of the actual 1981 spud dates and rig release dates shows a days on site figure of 1295. This difference is attributable to an unusual number of days associated with Hebron I-13 and Hibernia K-18. Substitution of the actual days for the forecasted days on Hebron I-13 and Hibernia K-18 yields 1262 days on site. This is a difference of 33 days or 2.5 percent. Because of this difference in days on site, 1295-1096 = 199, the expenditure estimate of 314 million dollars for 1981 could probably be understated by between 15 and 20 percent.

The current cost of drilling in the Newfoundland and Labrador offshore is approximately 245,000 dollars per day. This figure is based on 110,000 dollars per day for rig hire and 135,000 dollars per day for additional costs. These day rate figures vary considerably depending on the size and type of rig, the characteristics of the well, the timing of a contract and many other factors.

The 1981 drilling program is still being monitored and the actual information will be made available as soon as it becomes available.

When hiring a rig, the oil company must pay the cost of moving the rig to the desired drilling location. This cost can be either an agreed lump sum or a day rate charge that is slightly less than the normal day rate. The logic behind charging less while in transit is simply that the equipment is not being used and is not suffering the wear and tear of normal operation. Costs are also reduced because a full crew is not required at these times. The most variable components of the drilling costs are the rig hire and supply vessel hire elements. The remaining operation costs, being influenced to a lesser degree by the market, move broadly in line with inflation.

Tables 4:11-4:16 give the economic impact in terms of the expenditures on goods and services and employment. Total expenditures are presented for nine separate categories; namely, rigs, supply boats, helicopters, fuel, mud, cement, casing, logging and other. Tables 4:11-4:13 give the impact, in millions of current Canadian dollars, for the low, medium and high forecasts, respectively. Tables 4:14-4:16 provide the same information but in millions of constant 1982 dollars.

Table 4:17 compares the variation in the distribution of well costs of an exploration well and two types of development wells. The categories experiencing the greatest changes are helicopters, supply boats and casing as well as rigs under type II development drilling.

The decrease in helicopter costs is attributable to the lesser amount of time necessary to complete a development well. This time saving is achieved as a result of the increased efficiency the operator experiences as he acquires greater knowledge of the environment within which he is operating and because of the fact that abandonment procedures are not required. These two factors, along with the decreased mobilization and demobilization time, account for the reduction in rig rental costs on type I development drilling. Type II

TABLE 4:11

Total Expenditures by Major Category
Low Case
($ Millions Cdn. Current)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	154.15	33.22	13.51	24.02	10.76	2.75	21.26	11.07	100.18	370.93
1984	205.26	44.76	20.25	37.44	14.49	3.55	28.01	14.92	136.41	505.09
1985	263.08	58.05	24.95	45.30	15.43	4.41	35.03	19.35	172.27	637.87
1986	221.32	49.82	21.43	39.15	14.96	4.13	31.34	16.61	147.54	546.29
1987	139.09	30.64	15.01	31.38	10.05	2.81	20.28	10.21	96.01	355.49
1988	199.13	42.30	19.66	38.02	15.37	4.31	36.33	14.55	136.78	506.46
1989	240.63	50.97	21.78	43.64	21.22	5.29	67.75	19.32	174.12	644.72
1990	284.84	71.08	28.79	59.25	27.70	7.33	96.57	27.87	223.27	826.71
TOTAL	1815.01	403.97	175.53	339.66	135.95	36.79	352.60	141.62	1258.41	4659.53

TABLE 4:12

Total Expenditures by Major Category
Medium Case
($ Millions Cdn. Current)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	223.95	46.69	19.75	37.78	14.42	4.10	30.84	15.56	145.45	538.55
1984	385.01	83.58	36.42	66.67	27.31	6.89	53.19	27.86	254.16	941.09
1985	462.24	100.84	44.84	86.96	30.01	8.25	62.88	33.61	306.97	1136.60
1986	418.98	90.48	40.74	78.72	28.99	8.26	59.59	30.16	279.69	1035.61
1987	528.83	115.69	54.42	108.35	38.03	10.51	77.66	38.56	359.66	1331.72
1988	637.75	138.31	62.91	120.10	50.54	12.48	98.09	46.55	431.69	1598.41
1989	659.43	136.76	59.86	118.18	49.96	13.31	126.09	47.92	448.25	1659.76
1990	598.51	132.08	55.65	114.90	50.83	13.91	145.02	48.62	429.02	1588.54
TOTAL	4022.21	867.55	384.75	753.11	296.05	79.93	669.38	296.56	2726.73	10096.25

TABLE 4:13

Total Expenditures by Major Category
High Case
($ Millions Cdn. Current)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	319.67	65.58	28.10	55.18	19.68	5.87	43.68	21.86	207.06	766.68
1984	607.74	128.21	56.82	109.90	41.28	10.97	82.77	42.74	399 76	1480.18
1985	730.95	155.58	68.89	135.02	48.45	13.49	100.44	51.86	482.73	1787.42
1986	927.76	200.48	89.65	170.64	63.17	17.47	129.45	66.83	616.22	2281.68
1987	1130.39	242.80	113.23	2224.82	79.38	21.71	160.65	80.93	759.94	2813.85
1988	1178.85	250.14	113.83	219.86	93.17	24.01	180.28	83.83	793.26	2937.23
1989	1493.92	308.14	133.51	255.73	110.75	28.90	239.73	105.04	990.02	3665.74
1990	1644.58	358.41	156.75	302.93	125.97	33.92	292.70	124.07	1124.55	4163.89
TOTAL	8141.36	1734.47	770.94	1495.55	587.79	158.56	1245.73	584.87	5445.37	20162.64

TABLE 4:14

Total Expenditures by Major Category
Low Case
($ Millions 1982 Cdn.)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	142.73	30.76	12.51	22.24	9.97	2.55	19.68	10.25	92.76	343.45
1984	175.97	38.37	17.36	32.10	12.42	3.04	24.02	12.79	116.95	433.03
1985	208.84	46.08	19.80	35.96	12.25	3.50	27.81	15.36	136.76	506.36
1986	162.68	36.62	15.75	28.78	11.00	3.03	23.04	12.21	108.45	401.54
1987	94.66	20.86	10.22	21.36	6.84	1.91	13.80	6.95	65.34	241.94
1988	125.49	26.66	12.39	23.96	9.69	2.72	22.89	9.17	86.19	319.15
1989	140.41	29.74	12.71	25.46	12.38	3.09	39.53	11.27	101.60	376.19
1990	153.89	38.40	15.55	32.01	14.97	3.96	52.17	15.06	120.63	446.65
TOTAL	1312.18	290.62	126.45	243.33	95.47	26.01	238.97	100.77	900.50	3334.30

TABLE 4:15

Total Expenditures by Major Category
Medium Case
($ Millions 1982 Cdn.)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	207.36	43.23	18.29	34.98	13.36	3.79	28.56	14.41	134.67	498.65
1984	330.08	71.66	31.23	57.16	23.41	5.91	45.60	23.89	217.90	806.83
1985	366.94	80.05	35.60	69.03	23.82	6.55	49.91	26.68	243.68	902.27
1986	307.97	66.50	29.94	57.86	21.31	6.07	43.80	22.17	205.58	761.21
1987	359.92	78.74	37.03	73.74	25.89	7.15	52.85	26.25	244.78	906.35
1988	401.89	87.16	39.65	75.68	31.85	7.86	61.81	29.34	272.04	1007.28
1989	384.77	79.80	34.93	68.96	29.15	7.77	73.57	27.96	261.55	968.46
1990	323.36	71.36	30.07	62.08	27.46	7.52	78.35	26.27	231.79	858.25
TOTAL	2789.79	601.62	266.89	520.95	202.21	54.84	450.49	204.67	1883.83	6975.26

TABLE 4:16

Total Expenditures by Major Category
High Case
($ Million 1982 Cdn.)

Year	Rigs	Supply Boats	Heli-copters	Total Fuel	Mud	Cement	Casing	Logging	Other	Total
1982	107.51	23.12	10.15	21.45	5.96	2.21	16.03	7.71	71.83	265.98
1983	295.99	60.73	26.02	51.09	18.22	5.44	40.44	20.24	191.72	709.89
1984	521.04	109.92	48.71	94.22	35.39	9.41	70.96	36.64	342.73	1269.02
1985	580.26	123.50	54.69	107.19	38.46	10.71	79.73	41.17	383.21	1418.91
1986	681.94	147.36	65.90	125.43	46.43	12.84	95.15	49.12	452.94	1677.10
1987	769.33	165.25	77.06	153.01	54.02	14.77	109.34	55.08	517.21	1915.07
1988	742.87	157.63	71.73	138.55	58.71	15.13	113.61	52.83	499.89	1850.96
1989	871.69	179.80	77.90	149.22	64.62	16.87	139.88	61.29	577.67	2138.94
1990	888.52	193.64	84.69	163.67	68.06	18.32	158.14	67.03	607.56	2249.63
TOTAL	5459.14	1160.95	516.86	1003.83	389.87	105.70	823.28	391.11	3644.76	13495.48

TABLE 4:17

A Comparison of Costs
Exploration Well Cost vs. Development Well Cost
3000 Meters Drilled Depth/Grand Banks Area
($ Millions 1982 Cdn.)

Year	Rigs	Supply Boats	Heli-copters	Fuel	Mud	Cement	Casing	Logging	Other	Total
EXPLORATION:										
Amount	6.16	1.34	.50	.85	.50	.17	1.17	.45	4.12	15.26
Percent	40.37	8.78	3.28	5.57	3.28	1.11	7.67	2.95	26.99	100.00
DEVELOPMENT:										
Type I										
Amount	4.48	.71	.23	.57	.38	.15	2.22	.36	3.37	12.47
Percent	35.93	5.69	1.84	4.57	3.05	1.20	17.80	2.89	27.03	100.00
Type II										
Amount	0.48	.71	.23	.57	.38	.15	2.22	.36	3.37	8.47
Percent	5.67	8.38	2.72	6.73	4.49	1.77	26.21	4.25	39.78	100.00

development drilling operations are assumed to be conducted from the fixed platform and as such require essentially all the services of type I drilling with the exception of the rig rental charge.

Two factors contribute to the reduction in supply boat costs. Firstly, the decreased drilling time leads to a decrease in the number of days for which supply boat services are required and secondly, economies of scale enable the number of supply vessels necessary to service a development well drilling program compared to an exploration well program to be reduced.

The reduction in fuel cost is accounted for by a combination of the economies of scale in supply boat operations and time savings resulting from increased efficiency, decreased mobilization and demobilization and the absence of abandonment procedures.

Exploration wells usually do not require that casing be run the entire length of the well whereas in development wells the entire hole is cased and an additional smaller type of casing called tubing is also inserted. This extra casing requirement leads to increased cost in this category.

Three other categories; namely, drilling fluids, cement and logging, also experience differences in costs. As knowledge of the properties of the reservoir is gained, the operator can better predict the downhole pressures, thus enabling a reduction in the required volume of drilling fluid additives. A reduced requirement of these additives translates into direct cost savings. Abandonment of development wells occurs toward the end of the field life. Since this can be 20 or more years after the well is spudded the applicable cement costs are assumed to be associated with the abandonment procedures for the field and as such are excluded from drilling costs. A significant amount of time is devoted to evaluation and testing procedures during the exploration/delineation stages. These tests yield many valuable reservoir parameters which are essential to the selection of the appropriate development drilling program. By the time the platform site is selected and development drilling commences much of the testing previously conducted is no longer necessary. This decreased evaluation time is reflected in the logging cost category.

The "other" cost category deserves special mention. This category is the summation of many smaller cost categories which individually do not account for a significant portion of the costs but, as can be seen, when added together account for over one quarter of the total cost of drilling a well.

4.4 Employment

The work force employed as a result of offshore oil and gas drilling operations is divided into those working offshore and those working onshore. Onshore employment currently accounts for approximately 20 percent of the total during the peak drilling season and is defined here to be administrative and clerical support in the various company offices, helicopter pilots and mechanics as well as dockmen and warehousemen required for supply boat operations. Because of the nonlinear relationship between onshore employment and offshore activity this percentage figure is expected to decrease over time. Offshore employment includes drilling crews, marine crews and offshore support staff such as well surveyers, cooks, radio operators, divers, etc.

Tables 4:18-4:21 provide low, medium and high forecasts for manyears and peak employment associated with the expenditures contained in section 4.3.

TABLE 4:18

Forecast of Onshore Employment
(Manyears)

Year	Low	Medium	High
1982	332.3	332.3	332.3
1983	350.2	399.3	455.3
1984	367.7	468.5	552.0
1985	384.9	493.8	591.3
1986	387.5	490.3	651.3
1987	358.6	520.3	702.6
1988	390.4	554.1	714.3
1989	405.5	539.0	741.9
1990	394.5	499.0	750.5
TOTAL	3371.6	4296.7	5491.3

TABLE 4:19

Forecast of Peak Onshore Empl.
(No. of People)

Year	Low	Medium	High
1982	365	365	365
1983	306	444	528
1984	407	528	651
1985	428	557	701
1986	418	547	759
1987	371	589	830
1988	434	626	854
1989	429	605	867
1990	457	612	911

TABLE 4:20

Forecast of Offshore Employment
(Manyears)

Year	Low	Medium	High
1982	554.0	554.0	554.0
1983	714.7	1012.8	1431.3
1984	874.9	1632.9	2522.6
1985	1027.7	1793.4	2781.7
1986	798.4	1461.1	3239.8
1987	450.1	1697.2	3578.3
1988	584.2	1854.7	3363.5
1989	691.1	1742.6	3837.7
1990	881.1	1583.5	4071.2
TOTAL	6576.1	13332.1	25038.0

TABLE 4:21

Forecast of Peak Offshore Empl.
(No. of People)

Year	Low	Medium	High
1982	1152	1152	1152
1983	1364	1820	2756
1984	1580	2708	4312
1985	1796	2924	4768
1986	1344	2492	5200
1987	672	2924	5896
1988	1322	3118	5850
1989	1032	2852	6012
1990	1802	3384	6740

The employment numbers as calculated by our model assume a very efficient allocation of manpower. For this reason the forecasts provided probably understate the actual numbers to be employed. This modelling problem, coupled with the previously mentioned discrepancy between actual and estimated days on site for 1981 implies that the manpower data included for 1981 is also understated.

Table 4:22 compares the 1981 actual peak manpower requirement as provided by the Department of Labour and Manpower with the model's estimates. The discrepancy between actual and estimated onshore employment is accounted for by the inclusion, in the actuals, of summer students and other trainees in various company offices and the exclusion of seismic operations from the estimates. A larger discrepancy appears between actual and estimated offshore employment. Of the difference, 1609 - 1368 = 241, only the seismic related employment of 166 can be accounted for. The remaining 75 are still being analyzed and are believed to be attributable to the inclusion of trainees, visiting industrial representatives and the efficiency, and thus lean toward underestimation, of our model calculations.

Tables 4:23 and 4:24 present estimates of the total wages and salaries applicable to the above mentioned employment forecasts.

TABLE 4:22

A COMPARISON OF ACTURAL VS. ESTIMATED PEAK EMPLOYMENT FOR 1981

ACTUAL			ESTIMATED		
Offshore	Onshore	Total	Offshore	Onshore	Total
1609	392	2001	1368	386	1754

TABLE 4:23

Total Wages and Salaries
($ Millions Cdn. Current)

Year	Low	Medium	High
1982	27.98	27.98	27.98
1983	37.27	49.86	67.05
1984	48.09	82.38	121.18
1985	60.37	98.78	146.42
1986	55.48	92.46	186.12
1987	40.98	115.85	225.42
1988	54.78	138.65	236.14
1989	68.15	144.31	291.95
1990	87.73	144.76	338.48
TOTAL	480.81	895.01	1640.75

TABLE 4:24

Total Wages and Salaries
($ Millions 1982 Cdn.)

Year	Low	Medium	High
1982	27.98	27.98	27.98
1983	34.50	46.16	62.08
1984	41.23	70.63	103.90
1985	47.92	78.41	116.24
1986	40.78	67.96	136.81
1987	27.89	78.85	153.42
1988	34.52	87.37	148.81
1989	39.76	84.20	170.35
1990	47.40	78.21	182.87
TOTAL	341.98	619.77	1102.45

List of Petroleum Directorate Published Papers and Reports

Date	Title
Sept., 1980	Economic Analysis of the Hibernia Development
Nov., 1980	Exploration & Development of Hydrocarbon Resources Offshore Newfoundland & Labrador
Nov., 1980	Petroleum Resource Potential of Offshore Newfoundland & Labrador
Jan., 1981	Guidelines for the Approval of a Hibernia Development Plan (Draft)
Feb., 1981	Effects of the Federal Energy Policy on Offshore Newfoundland & Labrador
Feb., 1981	Proceedings of the Symposium on Production and Transportation Systems for the Hibernia Discovery
May 1981	Economic Impact of Future Offshore Petroleum Exploration
July 1981	Introduction to The Petroleum Industry
July 1981	Guidelines for the Approval of a Hibernia Development Program
July 1981	Province of Newfoundland and Labrador Accidental Occurrences Contingency Plan Concerning Offshore Petroleum Related Activities
Oct., 1981	Petroleum Potential of the Western Newfoundland Onshore Area
Aug., 1982	An Analysis of the Impact of a Nova Scotia Type Offshore Agreement on Newfoundland

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